PETROLEUMSTILSYNET

Investigation report

Report	
Report title Report of the investigation of the well control incident in well 31/2-G-4 BY1H/BY2H on the Troll field with the *Songa Endurance* drilling unit	Activity numbers 001054029 001054030

Security grading		
☑ Public	☐ Restricted	☐ Strictly confidential
☐ Nor publicly available	☐ Confidential	

Summary

Work was under way on 15 October 2016 to connect the tubing hanger secondary retrieving tool (THSRT) to the tubing hanger (TH) before pulling the TH at well 31/2-G-4 BY1H/BY2H on the Troll field.

At 09.33, the top drive with the completion string was raised six metres at the same time as large quantities of fluid and gas flowed out of control up through the rotary table. This flow lifted the 2.5-tonne PS-21 hydraulic slips and threw some two tonnes of bushings several metres across the drill floor. The fluid column reached right to the top of the derrick. Activation of a number of gas detectors led to local equipment shutdowns. Nobody suffered physical injury during the incident.

Statoil is operator for the field. Work on the well was conducted with the *Songa Endurance* semi-submersible drilling unit.

The well was shut in with the annular preventer (AP) and the blind shear ram (BSR) was then activated. The riser was immediately refilled with 54 m^3 of fluid. Subsequent observations showed that the BSR had not cut the string. Annular pressure eventually stabilised at 112 bar.

Emergency response personnel mobilised, with some exceptions, in accordance with the alarm instructions. Non-essential personnel were demobilised in the course of 15 October 2016 to other facilities and to land (Bergen). The second-line response organisations at Songa Offshore and Statoil mobilised in connection with the incident. Statoil also established a team in Bergen to provide 24-hour support for the normalisation process.

In connection with the kill operation, a leak was found in the string at the connection between the TH and the THSRT. The leak and a shallow-set plug prevented pumping through the string. Bullheading was initiated on 16 October 2016 by pumping kill fluid through the kill line into the annulus. The well was first stabilised on 26 October 2016 after a long and challenging period of normalisation work.

The direct cause of the incident was that large quantities of gas from the reservoir under the TH was released. A BOP wellhead connector test conducted about six hours before the incident probably cycled the primary barriers – the gas lift valve (GLV) and the flow control valves (FCVs). During this period, fluid from the well leaked out into the formation at the same time as gas from the reservoir flowed in under the TH.

The Petroleum Safety Authority Norway (PSA) regards this as one of the most serious well control incidents on the Norwegian continental shelf (NCS) since Statoil's Snorre A incident in 2004. This view is based on the incident's scope and potential. Under slightly different circumstances, it could have led to a major accident with loss of life as well as substantial material damage and emissions/discharges to the natural environment.

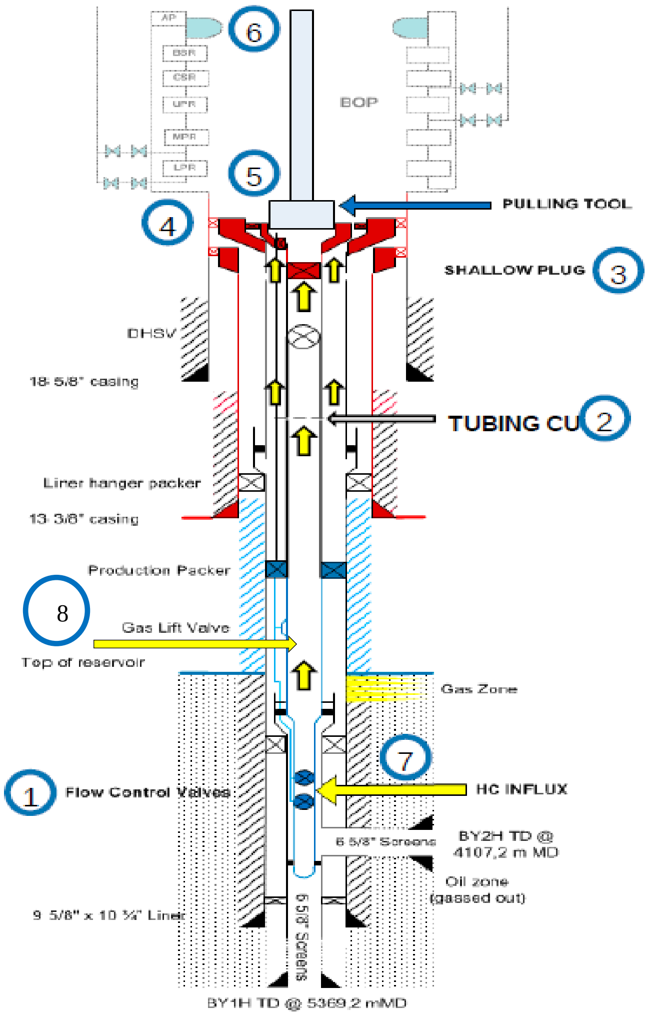
Involved	
Main group T-1	Approved by/date [Tilsynskoordinators underskrift / Dato for sluttføring av rapporten]
Members of the investigation team Amir Gergerechi, Eigil Sørensen and Jan Erik Jensen	Investigation leader Amir Gergerechi

Contents

Summary

In connection with pulling a tubing hanger (TH) on 15 October 2016, work was under way to connect the tubing hanger secondary retrieving tool (THSRT) to the TH in multilateral well 31/2-G-4 BY1H/BY2H (hereafter called G-4) on the Troll field operated by Statoil. The work was being done with the *Songa Endurance* semi-submersible drilling unit.

At 09.33, the top drive with the completion string was raised six metres at the same time as large quantities of fluid and gas flowed out of control up through the rotary table. This flow lifted the 2.5-tonne PS-21 hydraulic slips and about two tonnes of bushings, and threw the latter several metres across the drill floor. The fluid column reached right to the top of the derrick. Activation of a number of gas detectors led to local equipment shutdowns.



(1) FCV
(2) Tubing cut
(3) Shallow-set plug
(4) Wellhead
(5) Pulling tool
(6) AP
(7) Influx from reservoir through FCV
(8) Influx from reservoir through GLV

***Figure 1** Schematic illustration of the well.*

Nobody suffered physical injury during the incident.

The well was shut in with the annular preventer (AP) and the blind shear ram (BSR) was then activated. The riser was immediately refilled with 54 m^3 of fluid. Annular pressure eventually stabilised at 112 bar. Subsequent observations showed that the BSR had not cut the string.

Emergency response personnel mobilised, with some exceptions, in accordance with the alarm instructions. Non-essential personnel were demobilised in the course of 15 October 2016 to other facilities and to land (Bergen). The second-line response organisations at Songa Offshore and Statoil mobilised in connection with the incident. Statoil also established a team in Bergen to provide 24-hour support for the normalisation process.

In connection with the bullheading operation, a leak was found in the string at the connection between the TH and the THSRT. The leak and a shallow-set plug prevented pumping through the string. Bullheading was initiated on 16 October 2016 by pumping kill fluid through the kill line into the annulus. The well was first stabilised on 26 October 2016 after a long and challenging period of normalisation work.

The PSA decided on 17 October 2016 launch an investigation of the incident. The mandate for the investigation team included clarifying the course of events and assessing direct and underlying causes from a barrier perspective, with an emphasis on human, technological, organisational (HTO) and operational conditions. This mandate covered conditions up to 16 October 2016. A work group was appointed in the PSA to follow up the normalisation work.

The direct cause of the incident was that large quantities of gas from the reservoir below the TH was released. A BOP wellhead connector test conducted about six hours before the incident probably cycled the primary barriers – the gas lift valve (GLV) and the flow control valves (FCVs). During this period, fluid from the well leaked out into the formation at the same time as gas from the reservoir flowed in under the TH.

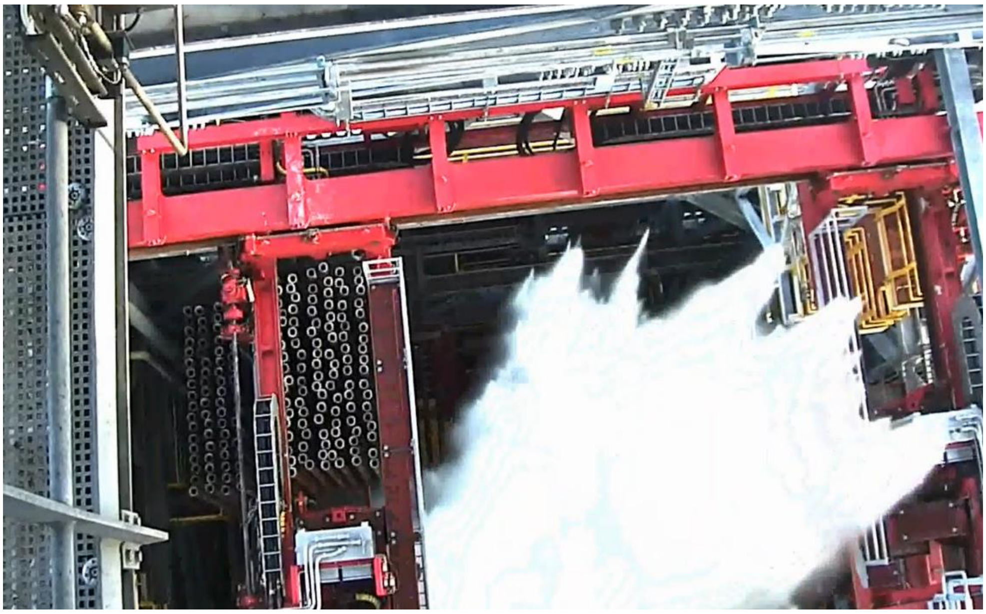


Figure 2 *Flow on* Songa Endurance *on 15 October 2016 seen from the top of the derrick. (Source: Songa Offshore)*

The PSA regards this as one of the most serious well control incidents on the NCS since the Snorre A incident in 2004. This view is based on the incident's scope and potential. Under slightly different circumstances, it could have led to a major accident with loss of life as well as substantial material damage and emissions/discharges to the natural environment.

Abbreviations and definitions

Annulus	Circular space between drill string and casing
AoC	Acknowledgement of compliance
AP	Annular preventer
BOP	Blowout preventer
BSR	Blind shear ram
Bullheading	Kill method, forcing drilling fluid back into the reservoir
Bushing	Liner which holds the hydraulic slips in place in the rotary table
Cat-D	Category D mobile unit
CSR	Casing shear ram
Cycle	Open and close (operate) valves
D&W	Drilling and well
DG	Decision gate
DOP	Detail operation procedure
DP	Dynamic positioning
DP-3	DP class 3 (highest safety class)
ESD	Emergency shutdown
FCV, HCM-A	Flow control valve, hydraulic control multiposition – adjustable
GE VetcoGray	General Electric, supplier of wellhead and TH
GLV	Gas lift valve
HTO	Human, technological and organisational
Kill fluid	Heavy fluid
Kill operation	Re-establish primary barriers with kill fluid
LEL	Lower explosion limit
LMRP	Lower marine riser package
MD	Measured depth along the well path
ME plug	Medium expansion
MOC	Management of change
NCS	Norwegian continental shelf
PP&A	Permanent plug and abandonment
PS-21 power slips	Hydraulic wedge to carry weight of the string in the rotary table
Red zone	Area of drill floor with restricted access
SLS	Single line switch
Subsea systems	Include TH, WH, VXT – see definitions below
TH	Tubing hanger
THSRT	Tubing hanger secondary retrieving tool
TMAP	Troll main activity programme
Top drive	Derrick-mounted drilling drive
TR	Temporary refuge
VXT	Vertical Xmas tree
WH	Wellhead
WOR	Workover riser
XMT	Xmas tree

List of figures

1 Introduction

Troll is a gas and oil field in the northern North Sea, about 65 kilometres west of Kollsnes near Bergen. It comprises two main structures – Troll East and Troll West. The field extends over 750 square kilometres in North Sea blocks 31/2, 31/3, 31/5 and 31/6. The water depth in the area is about 350 metres. Discovered in 1979, Troll contains extremely large gas resources as well as being one of the largest oil producers on the NCS. The original plan for development and operation (PDO) was approved in 1986, and the field came on stream in 1995 (source: www.norskpetroleum.no).

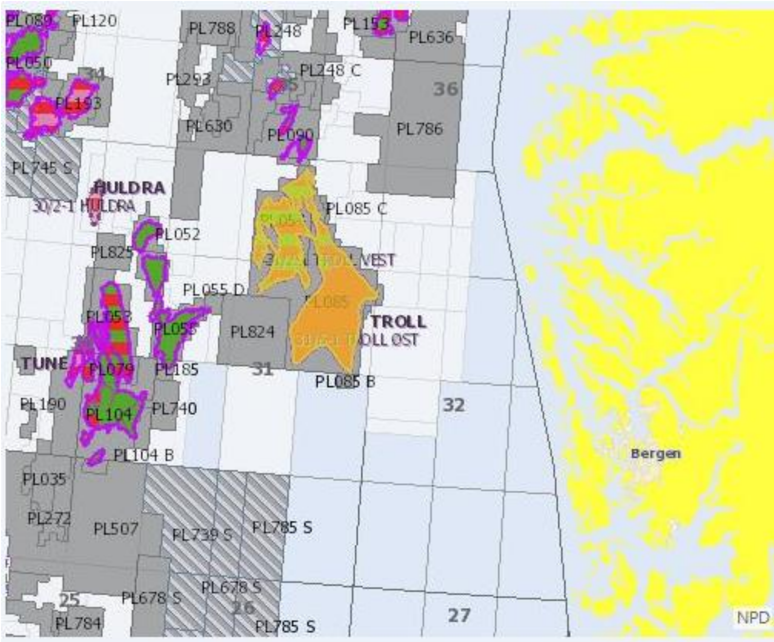


Figure 3 *Location of the Troll field. (Source: Norwegian Petroleum Directorate fact pages)*

Well G-4 is located in the G template on the Troll West structure, which is tied back via production flowlines to the Troll B platform (see figure 4).

Statoil is operator for the Troll A, B and C platforms. Songa Offshore is the drilling contractor for Statoil on the Troll field.

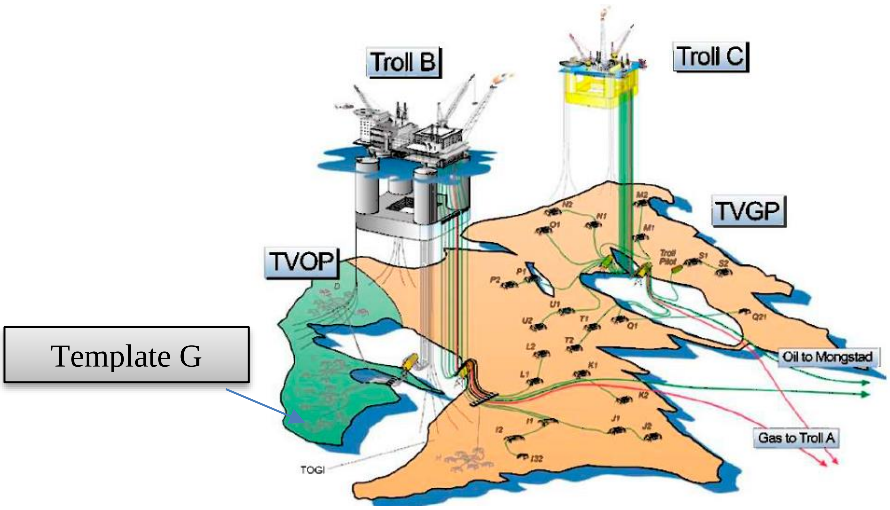


Figure 4 *The Troll field with platforms.*

Songa Endurance is a semi-submersible drilling unit built at South Korea's Daewoo yard in 2014 to the GVA 4000 design. It is one of Songa Offshore's four Cat-D drilling rigs. Songa Offshore secured an acknowledgement of compliance (AoC) from the PSA for *Songa Endurance* in December 2015. Statoil obtained consent to use *Songa Endurance* for drilling and completion activities on the Troll field in December 2015.

Figure 5 *The* Songa Endurance *semi-submersible unit. (Source: www.google.no)*

The incident occurred on 15 October 2016 in connection with pulling the TH. During the work of connecting the THSRT to the TH in well G-4, the top drive with the completion string was raised six metres out of control at the same time as large quantities of fluid and gas flowed out of control up through the rotary table. This flow lifted the 2.5-tonne PS-21 hydraulic slips and some two tonnes of bushings, shifting them several metres across the drill floor. The fluid column reached right to the top of the derrick. Activation of a number of gas detectors led to local equipment shutdowns. Two detectors gave readings of 60 per cent LEL.

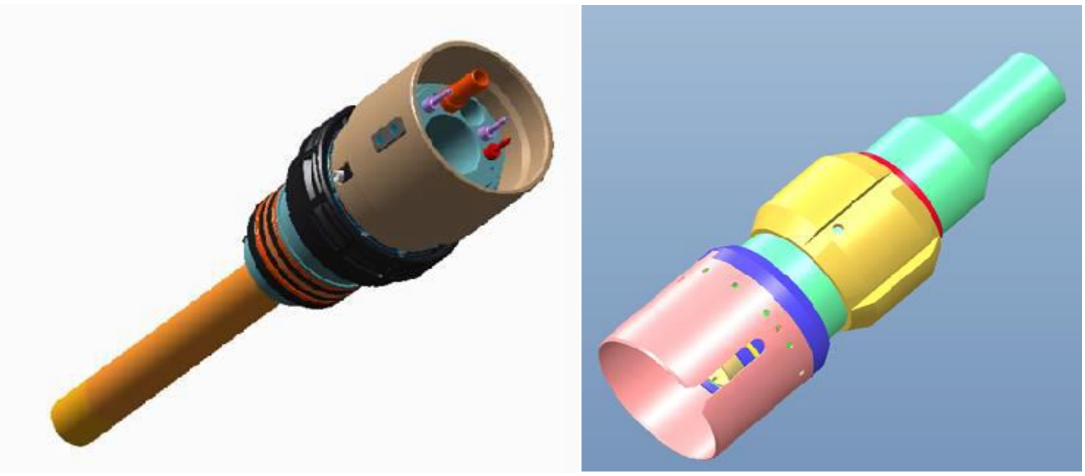


Figure 6 *The tubing hanger (TH) and tubing hanger secondary retrieval tool (THSRT). (Source: GE VetcoGray)*

The well was shut in with the AP and the BSR was then activated. The riser was immediately refilled with 54 m^3 of fluid. Subsequent observations showed that the BSR had not cut the string.

Bullheading proved challenging because of a leak in the string at the connection between the TH and the retrieval package. Pumping through the string was prevented by the leak and a shallow-set plug. The leak in the string occurred because the THSRT had not been fully screwed on while it was being connected to the TH before the incident. The kill operation began on 16 October 2016 by pumping kill mud down the well via the kill line and into the annulus.

This report presents the results of the PSA's investigation of the well control incident in well G-4 on the basis of the mandate for the investigation.

1.1 The PSA's follow-up of the incident

The PSA was notified by Statoil at 12.30 on 15 October 2016. The duty emergency response officer mobilised resources to follow up Statoil's work on safeguarding personnel and dealing with the loss of well control.

The PSA decided on 17 October 2016 to conduct its own investigation of the incident.

Composition of the investigation team:
Amir Gergerechi – drilling and well technology discipline (investigation leader)
Eigil Sørensen – drilling and well technology discipline
Jan Erik Jensen – logistics and emergency response discipline

1.2 Mandate for the PSA's investigation team

The mandate for the PSA's investigation accords with section 4.1.2 of the procedure.

a. *Clarify the incident's scope and course of events, with the emphasis on safety, working environment and emergency preparedness aspects.*
b. *Assess the actual and potential consequences.*
    1. *Harm caused to people, material assets and the environment.*
    2. *The potential of the incident to harm people, material assets and the environment.*
c. *Assess direct and underlying causes, with an emphasis on human, technological, organisational (HTO) and operational aspects from a barrier perspective.*
d. *Discuss and describe possible uncertainties/unclear aspects.*
e. *Identify nonconformities and improvement points related to the regulations (and internal requirements).*
f. *Discuss barriers which have functioned (in other words, those which have helped to prevent a hazard from developing into an accident, or which have reduced the consequences of an accident).*
g. *Assess the operator's own investigation report (with the assessment conveyed in a meeting or by letter).*
h. *Prepare a report and a covering letter (possibly with proposals for the use of reactions) in accordance with the template.*
i. *Recommend – and contribute to – further follow-up.*

1.3 Restrictions

The investigation has covered the identification of direct and underlying causes of the incident up to 16 October 2016. A dedicated group was appointed in the PSA to follow up normalisation work after the incident.

The investigation team has not conducted its own analysis of the reasons for the high torque when connecting the THSRT to the TH. In this connection, it has assessed the report from the supplier dated 22 November 2016 (GE VetcoGray – reference 164).

1.4 Interviews, verification on the unit and assessment of documents

Interviews were conducted during the investigation with personnel involved in the land organisation and on the unit. Personnel involved were interviewed as they came ashore and no longer had a role in the normalisation work. Land-based personnel were interviewed after the well control incident had been normalised. The interviews were conducted in Bergen and Stavanger. Inspections on the unit were postponed because of Statoil's normalisation of operation after the incident. A site inspection on *Songa Endurance* was carried out by the investigation team on 1 November 2016. Documents were also reviewed as part of the investigation. A total of 33 people were interviewed during the investigation.

2 Course of events

This chapter describes the course of events based on information and status reports in:

- standard time log
- the daily drilling report system (DDRS)
- interviews with people involved in the incident
- logs related to the emergency response.

Activities are described in chronological order. A schematic description is provided in the appended HTO diagram (appendix A).

2.1 Planning

Drilling activities on Troll take place in wells which have previously been completed and which are or have been on stream. As production declines, the reservoir section is plugged and sidetrack drilling initiated at the desired depth. A new reservoir section is drilled and the well completed for production. The wellhead and other existing infrastructure are accordingly reused.

The production wells on Troll are drilled as multilaterals with two or more sections in the reservoir. The 12 ¼-inch section is landed out horizontally in the reservoir, and windows for the multilateral sections are installed there. All the sections are drilled with water-based mud.

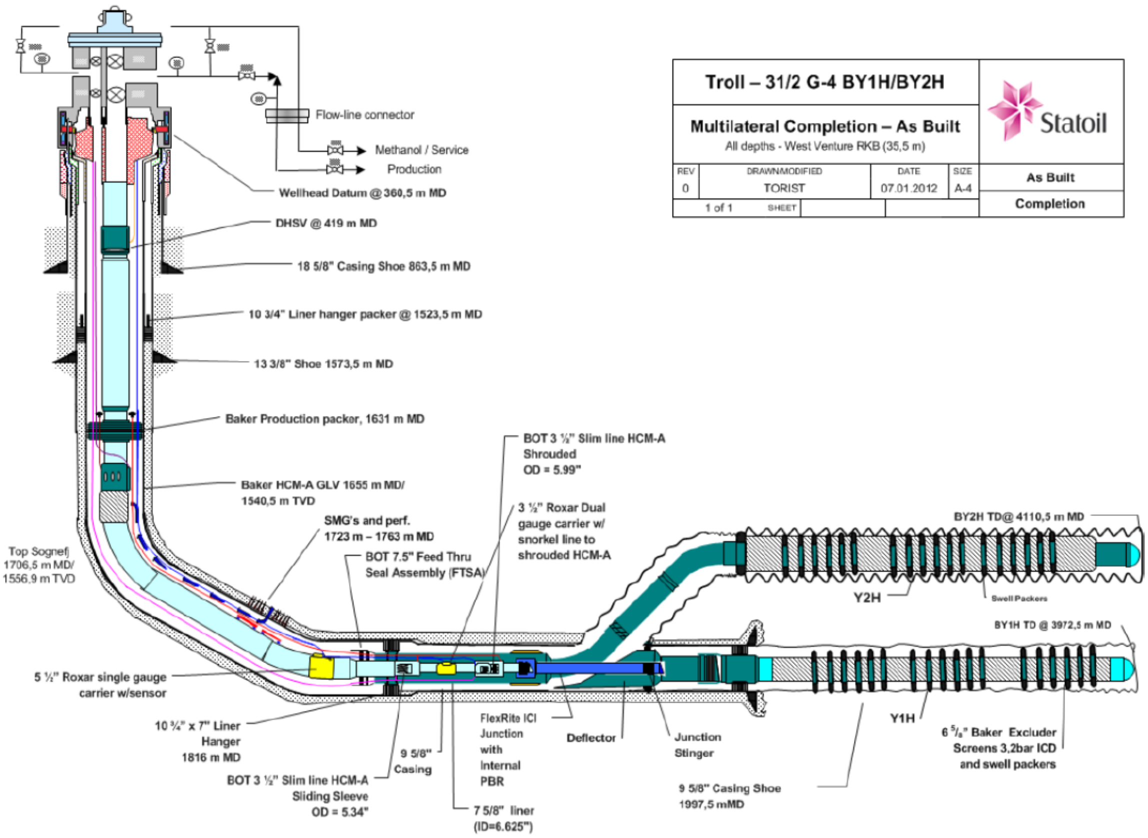


Figure 7 *Well diagram reflecting the status before the operation kicked off. (Source: Statoil)*

The operation to be conducted in well G-4 is known as slot recovery. This is intended to prepare for drilling a sidetrack after permanent plug and abandonment (PP&A) of the original well path. Well G-4 is a subsea completion in the G template with a wellhead (WH) and vertical Xmas tree (VXT) from GE VetcoGray. In connection with the slot recovery operation, the Xmas tree was replaced by a blowout preventer (BOP).

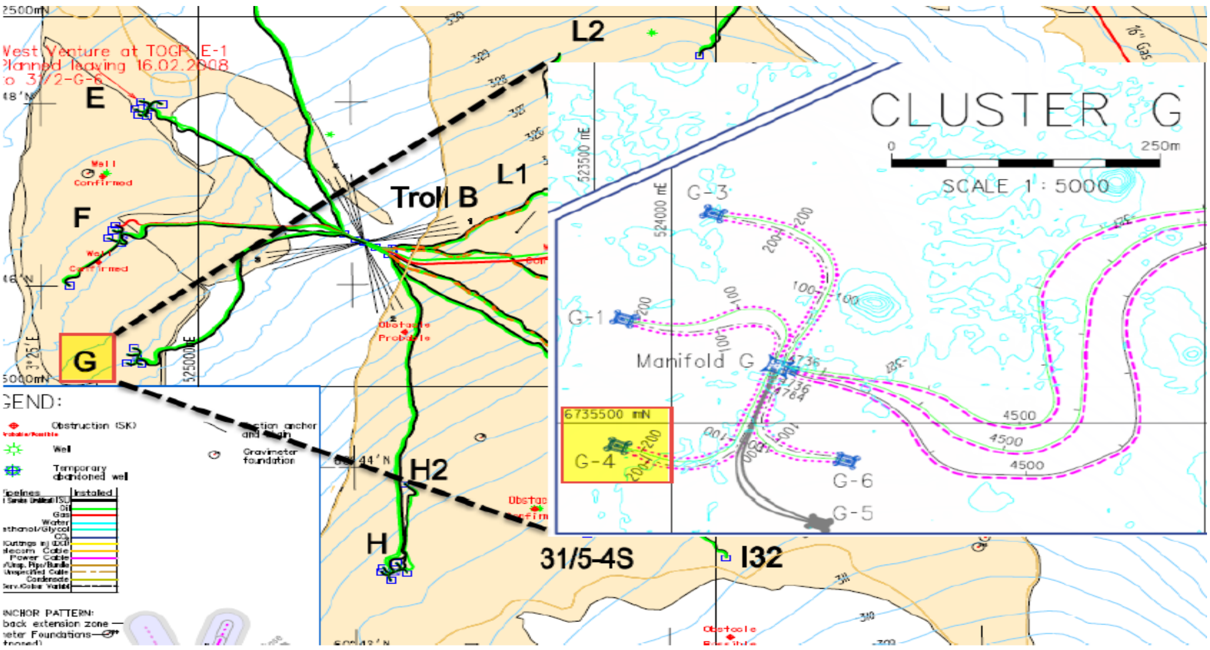


Figure 8 *Location of the G template on the Troll field. (Source: Statoil)*

The G-4 well was drilled by the *Songa Trym* mobile drilling unit in 2011 and then completed as an oil producer with two producing sections in the reservoir by the *West Venture* mobile drilling unit in 2012.

2.1.1 Vertical and horizontal Xmas trees

Most of the wells on Troll are fitted with horizontal Xmas trees (HXTs) delivered by Aker Solutions ASA (Aker). A small number have VXTs delivered by GE VetcoGray. The main difference between these types is that, with the VXT, the TH is locked to the wellhead before the tree is installed. THs on HXTs are installed and locked in the tree itself. In addition, pressure can be measured under the TH in wells with HXTs. That is not possible with VXTs.

2.1.2 Concept selection

Statoil has established a Troll main activity programme (TMAP) document to standardise and improve PP&A operations on the field. Signed in 2015, this recommends the use of deep-set plugs in wells with VXT systems before pulling the TH. Section 4.3.8 of the TAMP notes that all pressure testing will affect the FCV and GLV control lines.

The concept selection approval meeting for the design of a new sidetrack in G-4 took place on 15 February 2015 between representatives from Statoil’s drilling and well (D&W) and petroleum technology (Petec) departments. The use of the FCV and GLV as a barrier element was not discussed there.

The concept selection report for drilling a new sidetrack in G-4 was signed on 11 March 2016. Its base case shows a well diagram where the PP&A design includes a deep-set plug.

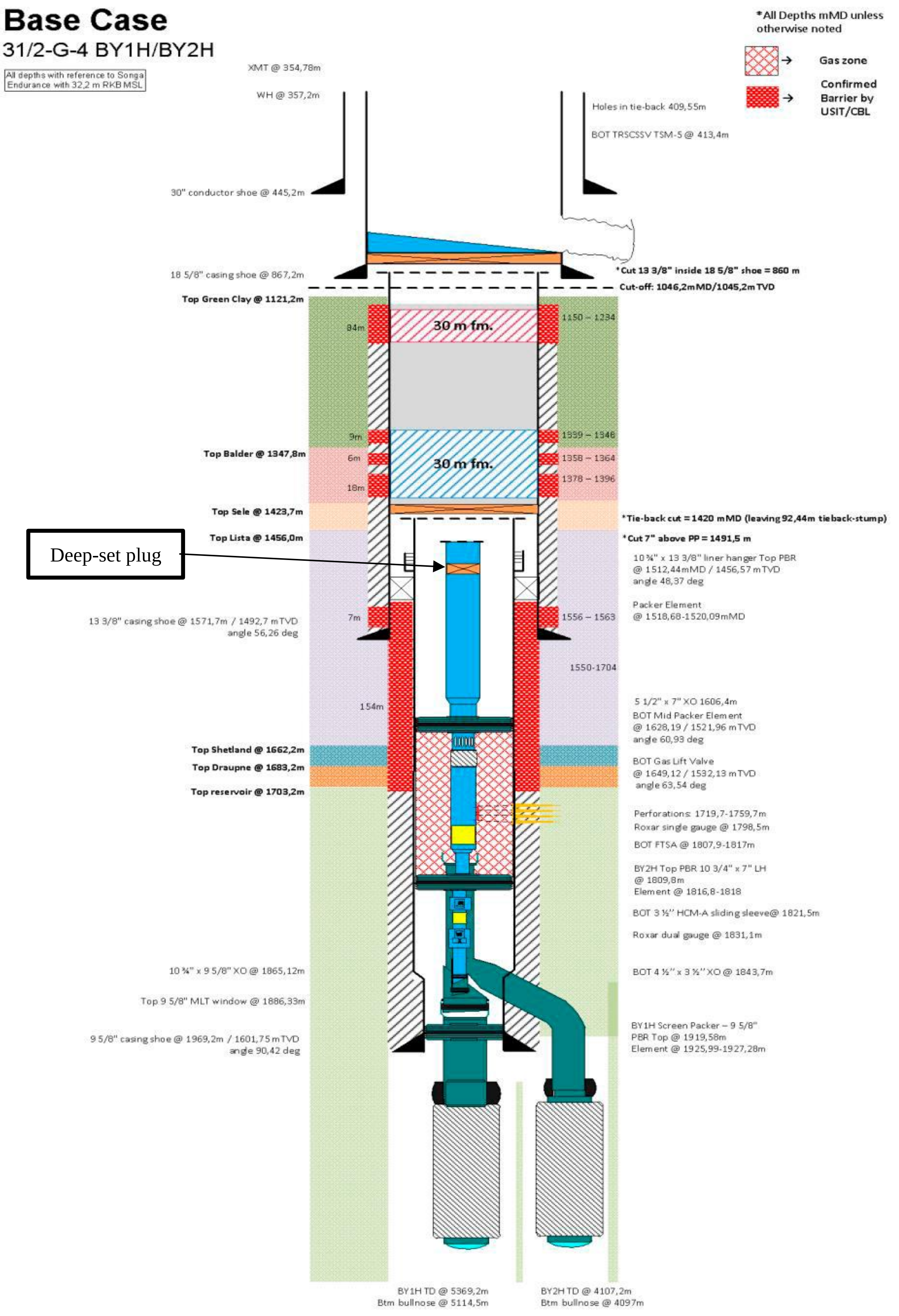


Figure 9 *Diagram from the concept selection report.*

2.1.3 Risk review

The investigation team is aware that Statoil held two meetings where key risks for plug and abandonment (P&A) in well G-4 were discussed. These risk assessment meetings took place on 15 February 2016 and 28 June 2016. No list of participants is available for any of the risk reviews conducted for this PP&A activity. Documentation received shows that representatives from the suppliers of subsea systems or FCV/GLVs (GE VetcoGray and Baker Hughes respectively) were not invited to participate.

2.1.4 Use of the FCV and GLV as a barrier element

The PP&A operation in G-4 is the first in a well with a VXT to be planned with the FCV and GLV as the primary barrier rather than a deep-set plug. A deep-set plug is a mechanical unit positioned in the production tubing above the reservoir before pulling the tubing in a conventional PP&A operation.

The final programme for the PP&A operation in G-4 was approved on 8 July 2016 with the FCV and GLV as a barrier element. It emerged from interviews that the risk of replacing a deep-set plug with the FCV and GLV as barrier elements was not assessed in the process from the concept selection approval meeting of 15 February 2016 until the final programme was approved.

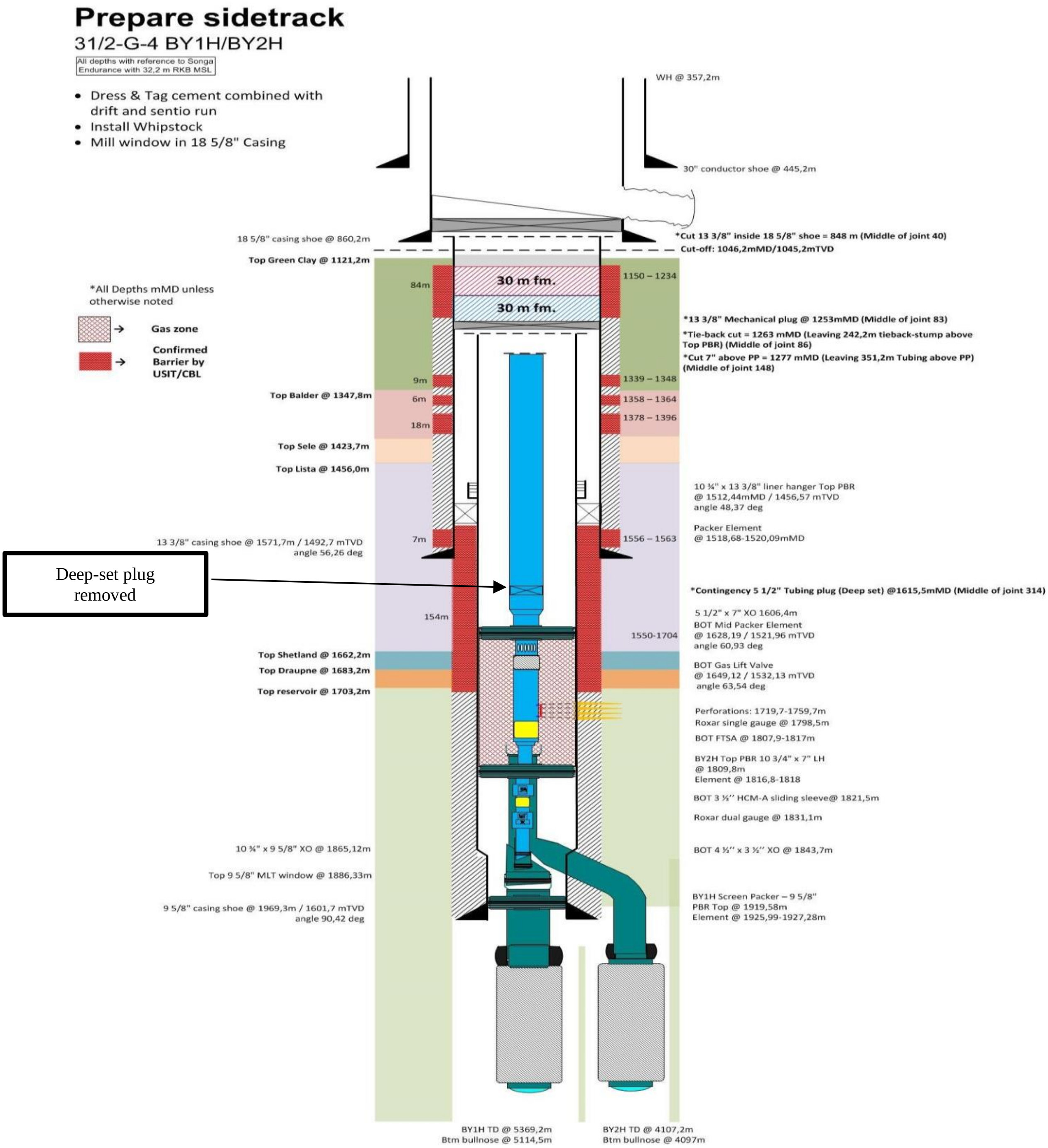


Figure 10 *Diagram from the PP&A programme.*

2.1.5 Gas lift in well G-4

Gas from the gas cap overlying the oil zone in the Troll field is used to lift oil in the well from the reservoir to the surface. The completion string passes through the gas zone and down into the oil zone. A GLV is installed in the gas zone to admit gas to the production tubing and mix it with the flow. The gas allows the oil to flow up more freely.

2.1.6 Operation of the GLV and FCV

The FCV and GLV are installed on the production tubing to control the oil and gas flow from the reservoir into the tubing. They are operated hydraulically through ¼-inch control lines. The latter are led from the valves and up along the production tubing to the TH, where they terminate in a check valve known as a poppet (see figure 14).

These poppet valves can be opened by pressure from above but not from below. Hydraulic control of the valves from the surface is provided via the Xmas tree. The FCVs and GLVs are controlled from the surface after the installation of the VXT. When the latter is removed, the poppet valves are exposed to pressure from above and unprotected. They can be opened or closed (cycled) by the application of hydraulic pressure through control lines of 28-138 bar.

Figure 11 *Poppet valves inside the TH. (Source: GE VetcoGray)*

A Vetco TH is limited to three poppet valves, where up to three hydraulic control lines can be used to control four valves down in the production tubing – one for the downhole safety valve (DHSV), one for the GLV and one for two FCVs. The FCVs are connected in series with the aid of a single line switch (SLS) and controlled by only a single control line.

Figure 12 *Single line switch (SLS).*

Baker Hughes is the supplier of the FCVs and GLV with associated control lines, while the TH with poppet check valves comes from GE VetcoGray.

2.1.7 Overview of dispensations (Disp) for the P&A operation in the G-4 well

The project manager for G-4 applied for three dispensations from Statoil's internal requirements in connection with the permanent plugging operation in the well. All these applications were approved. Table 1 provides an overview.

Disp 145458 applied only to the GLV and not the FCV. According to interviewees, the FCV was approved as a barrier element. Documentation received subsequently shows that the company's internal requirements for using GLVs and FCVs as barrier elements were not met pursuant to TR 2385 B.3.2 item 6.

***Table 1** Overview of dispensations in connection with the P&A in G-4.*

Disp	Status	Description	PSA's comments
145458	Approved	Use of GLV as barrier element in place of deep-set plug in well G-4. Dispensation from TR 3507 and TR 2385.	Internal requirements for using GLV as barrier element not met pursuant to TR 2385 B.3.2 item 6. See section 3.2.4.
145499	Approved	Transport of pipes without thread protection.	Not relevant for the investigation.
145922	Approved	Pulling the VXT with only one barrier against reservoir pressure in the well – 31/2 G-4 BY1H/BY2H P&A. The ground for dispensation are that having two barriers against reservoir pressure is not possible with the GE VetcoGray wellhead system when pulling the VXT. Dispensation from TR3507.	Internal requirements for use of GLV/FCV as barrier element not met pursuant to TR 2385 B.3.2 item 6. See section 3.2.4.

2.1.8 Detailed operating procedure (DOP 090) for pulling TH

Documentation received shows that the detailed procedure for pulling the TH (DOP 090) was completed on 12 October 2016. Comments in interviews indicate that the procedure was amended on 14 October. The AP was originally due to be closed during connection of the THSRT to the TH. This closure was postponed until the TH was being pulled. According to information obtained from interviews, this change was intended to make it easier to connect the THSRT to the TH. Torque readings are more difficult to take during connection of the THSRT when the AP is closed.

Statoil	Detail Operation Procedure		Songa Offshore	
Rig	Songa Endurance	DOP 090 Pull TH & upper completion using THSRT	Rev.	0
Well	G-4		Date	12.10.2016
Field	Troll		Status	FINAL

№	Main activity / Operational Description	Comments / Risk
5. Driller	Land and latch THSRT to TH. 1. M/U landing stand to topdrive. 2. Vent string to atmosphere. 3. Take up/down weight and free rotation torque of the running	**Note:** Line up mud pumps / cement pumps on 1.03 SW **Risks:** **Activity Reminders:**

№	Main activity / Operational Description	Comments / Risk
8. Driller	Unlocking TH. 1. Choke line to be open against closed choke. 2. Unlock the TH Locking Sleeve by perform an 18 ton over pull. The string shall move up 3" / 75mm, use laser. Do not continue lifting after achieved 3" /75mm. Due to possible gas below TH. Avoid rotation at this phase.	Risks: Activity Reminders: Parallel Activities:
9. Driller	Finalize THSRT and TH makeup. 1. Apply 2-4 RH turns until 6700 Nm torque build up, this will fully connect the TH and THSRT 2. If not sufficient rotation is obtained, apply small over pull in steps of 5 tons until a total of 6 turns are achieved.	Risks: Activity Reminders:
11. Driller	Pull up for closing annular above TH. Max pull capacity on THSRT 147 ton + landing string 11 ton = 158 ton on weight indicator. No trapped gas below TH to be expected. 1. Close annular. 2. Increase pull to pull upper completion free and pull up approx. 1m .	Risks: Gas below TH Activity Reminders: • 3 ea hyd. control lines and 1 ea Roxar E-line will part down hole when pulling Tbg hanger free

***Figure 13** DOP 090 for pulling the upper completion.*

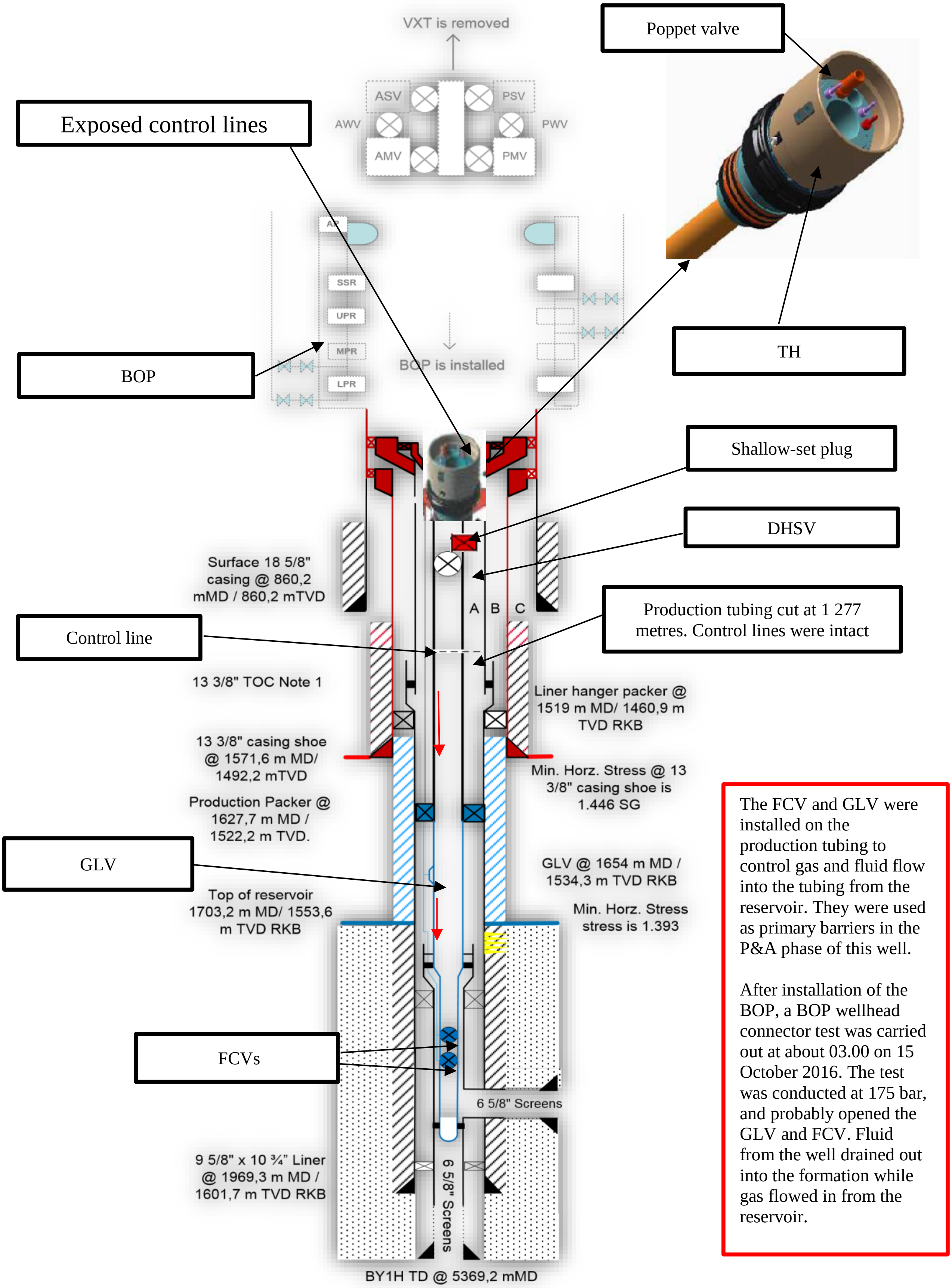


***Figure 14** Control lines with poppet valves on the TH after removal of the VXT and installation of the BOP.*

2.2 Execution

Date	Time	Event	Comment
16.9.2016		*Songa Endurance* arrived on location on Troll to start the PP&A and subsequent drilling of a sidetrack in well G-4. After the unit had been moored, work began on connecting to the well with the workover riser.	
20.9.2016		GLV closed and FCV opened.	Work done from the unit by valve supplier (Baker Hughes).
20.9.2016		Well bullheaded with seawater. FCV closed and pressure-tested to 190 bar.	
20.9.2016		Production tubing string cut at 1 277 metres measured depth (MD).	Based on information about the type of cutting tool and the pressure test diagram for the BOP connector test, the investigation team assumes that control lines were intact after the cut.
22.9.2016		A shallow-set medium expansion (ME) plug was installed in the annulus and the production tubing at 391 metres.	
22.9.2016		*Songa Endurance* was taken out of service because of a labour dispute between the Norwegian Oil and Gas Association and the Industry Energy union. The workover riser was disconnected from the well.	Strike.
12.10.2016		Activity resumed on the unit after the strike was called off.	

Date	Time	Event	Comment
13.10.2016		The VXT was retrieved and the BOP with riser installed on the well.	
15.10.2016	03.00	BOP connector test carried out at 175 bar.	This pressure test probably opened the GLV and FVC. Fluid from the well drained out into the formation while gas flowed in from the reservoir.
15.10.2016		THSRT run into the well and landed on the TH.	
15.10.2016		Problems connecting the THSRT to the TH. Increased torque (30kNm) was used to screw the tool to the TH. Because of clarifications needed when increasing torque (from 10 to 30kNm), senior personnel (senior tool pusher and drilling supervisor) were present in the driller's cabin.	At this point, the THSRT was locked to the TH but the connection was not tight.
15.10.2016		The string had to be raised 7.5cm to complete the remaining rotations in order to secure a pressure-tight connection between THSRT and TH.	At this point, the AP was completely open, planned maximum overpull was 18 tonnes.
15.10.2016	09.33	When the overpull reached 13 tonnes, the top drive with the THSRT and the completion string was suddenly raised six metres. After a few seconds, large quantities of fluid and gas flowed out of control up through the rotary table.	Nobody was out on the drill floor in the red zone (marked area on the floor subject to movement restrictions).

Figure 15 Outflow of gas and fluid at the fingerboard level. (Source: Songa Offshore)

This flow lifted both the 2.5-tonne PS-21 hydraulic slips and some two tonnes of bushings, shifting the latter several metres across the drill floor. The fluid column reached right to the top of the derrick, about 50 metres above the drill floor. Large quantities of fluid/gas prevented personnel in the driller's cabin seeing what was going on outside. Figure 17 shows where the bushings landed. One length of bushing hit and damaged the railing on the work basket before landing on the deck grating alongside the drillpipe store (figure 16).

Figure 16 Damaged railing and deck grating.

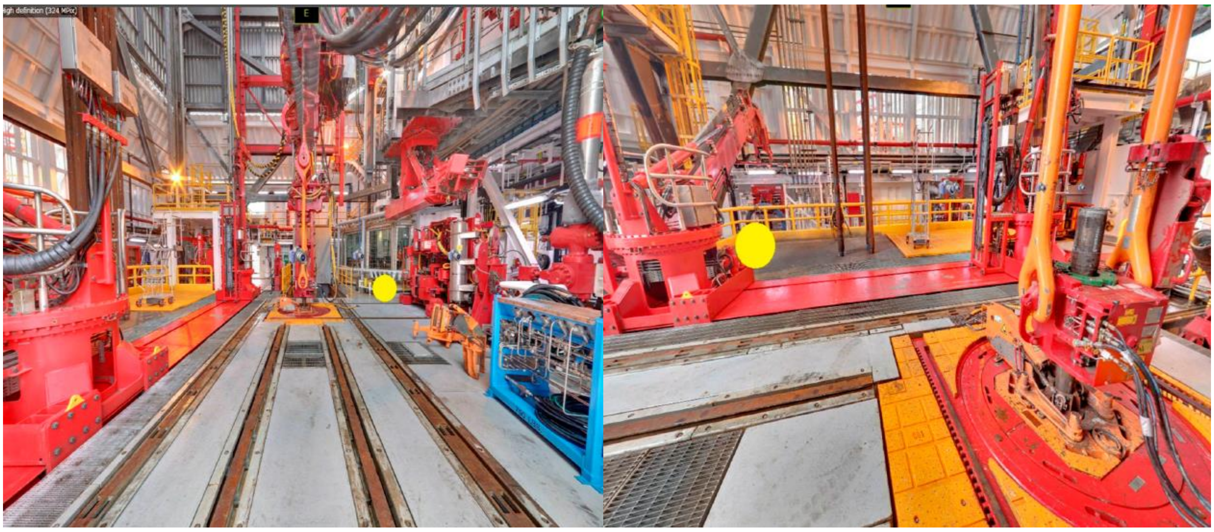


Figure 17 *Position of bushings after the incident on the drill floor (marked with yellow circle).*

The AP was activated at about 09.34 on 15 October 2016, followed by activation of the BSR.

When the flow of fluid and gas decreased, the PS-21 hydraulic slips landed under the rotary table and on top of the diverter.

Figure 18 *The PS-21 slips.*

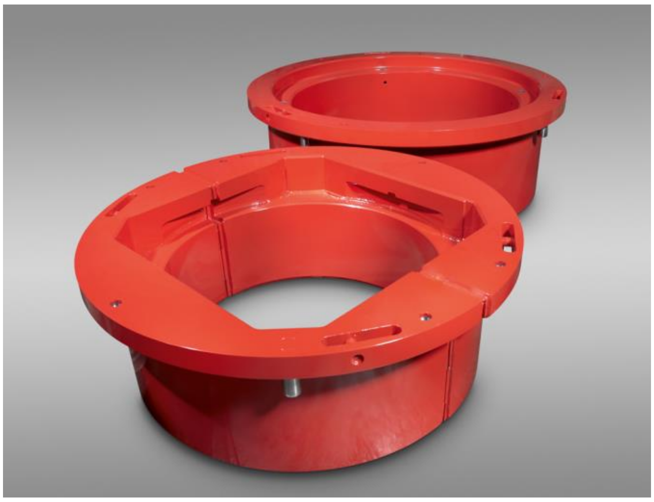


Figure 19 Bushings.

A general alarm was activated at 09.33. A number of gas detectors on and immediately outside the drill floor were activated about one minute after the drillstring was raised. This led to local emergency shutdowns (ESDs) of equipment, and mustering was initiated.

The riser was immediately refilled with 54 m^3 of fluid. Casing pressure stabilised at 112 bar. Nobody suffered any physical injury during the incident.

Mustering to the living quarters was implemented during the incident because of the threat of hydrocarbons (gas) outside. Personnel without emergency response duties mustered to the temporary refuge (TR) in the mess area on the main deck.

Pursuant to the alarm instruction, the offshore installation manager (OIM), the barge master, the technical supervisor, the senior tool pusher, the operator's representative (drilling supervisor) and the storekeeper are to muster in the emergency response centre (by the control room). The senior tool pusher and drilling supervisor were in the driller's cabin on the drill floor during the incident and did not muster as planned in the procedure.

All personnel on board (POB) were accounted for at 10.02. This process took 28 minutes, compared with the internal requirement of 12 minutes. According to interviewees, this was because representatives from the operator and equipment suppliers did not muster as specified in the plans.

M/S *Stril Mercur*, the area standby ship, arrived on location at 11.45. It was informed of the incident and left its position near Oseberg South at 09.40.

2.3 Handling of the well control incident on 15 October 2016

The BOP was activated by drilling personnel immediately after the observation of a rising fluid column on the drill floor and after the string shot up. First, the AP was closed and the BSR was then activated immediately afterwards.

After the well had been shut in with the BOP, it took about 45 minutes for the pressure in the annulus to stabilise because of a leaking choke valve on the choke manifold. Closing a valve behind the choke allowed the pressure to stabilise. The leaking choke caused a further outflow of gas from the well after the AP had been closed.

Non-essential personnel were transferred during 15 October 2016 to other facilities and to land. A total of 24 people were removed from *Songa Endurance* in that context.

2.4 Normalisation

The first stage of kill operation started on 16 October 2016 with bullheading kill fluid into the well annulus through the kill line. Pressure in the annulus was stabilised after the well fluid had been pushed back into the formation with kill fluid.

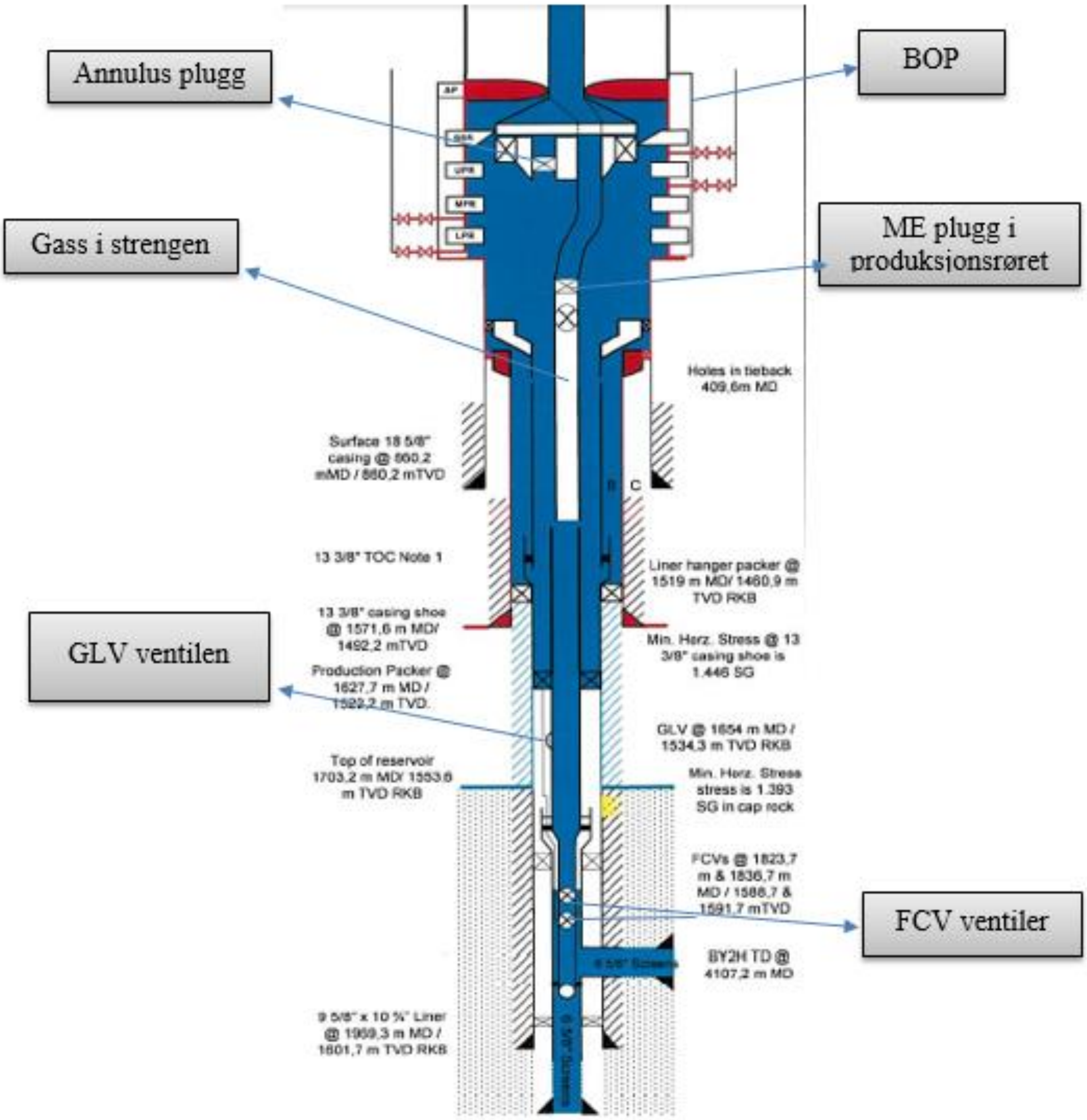


Figure 20 *Well diagram after establishing the primary barrier in the annulus. Dark blue indicates intrusion of kill fluid. Key: Annulus plug, Gas in string, ME plug in production tubing.*

The combination of the leak and the ME plug in the string hindered pumping of kill fluid down the string. This meant the string above the cut point remained standing with gas inside. The leak in the string arose because the retrieval tool for the TH was not screwed fully tight during connection before the incident occurred. The kill operation was therefore challenging.

The second stage of the kill operation involved bullheading the contents (gas and fluid) in the production tubing string back to the reservoir.

Additional drilling personnel were sent out as reliefs and to assist in the normalisation work. The well was normalised on 27 October 2016.

After normalisation, repairs were carried out to damaged equipment on the drill floor, including the electric motor on the top drive and the PS-21 hydraulic slips.

3 Causes

3.1 Direct

The direct cause of the incident was that large quantities of gas from reservoir below the TH were released. The BOP wellhead connector test carried out about six hours before the incident most probably cycled the GLV and FCV primary barriers. During this period, fluid from the well leaked into the formation while gas from the reservoir flowed under the TH.

3.2 Underlying

The investigation shows that the underlying causes of the uncontrolled flow from the well are multiple and complex, but can primarily be related to planning, management of change, expertise and understanding of risk.

3.2.1 Planning the FCV and GLV as a barrier element

The PP&A operation on G-4 is the first to be planned with the FCV and GLV as primary barriers, replacing the deep-set plug. A deep-set plug is a mechanical unit installed in the production tubing above the reservoir before pulling the Xmas tree and production tubing string. According to information received, the intention was to reduce operation time by about 12 hours – the time it takes to install the deep-set plug.

According to Statoil, the FCV and GLV have been used as barrier elements in a subsea VXT system once before, but for a limited operation (replacing an Xmas tree with production tubing intact).

Pressure readings and calculations after the well was shut in show that it had direct communication with the reservoir. The FCV and GLV were unintentionally cycled to the fully open position during the BOP wellhead connector test. Gas flowed in from the reservoir to the well because the primary barrier failed. The risk of cycling the FCV and GLV to the open position was not identified when planning and preparing the operation. Risk assessment meetings were held without the presence of relevant personnel from the supplier. The pressure of 175 bar during the connector test was transferred through the poppet valves and control lines along the production tubing down to the GLV and FCV, and was sufficient to cycle them. The connector test was conducted as planned at 03.00 on 15 October 2016 to verify that the BOP was connected to the wellhead (see section 2.1.6).

3.2.2 Concept selection

According to documents received from Statoil (*Concept Selection Report Well 31/2-G-4CY1H/CY2H/CY3H Troll*) the base case for the plugging operation on G-4 was approved on 10 May 2016. The FCV and GLV were not mentioned as barrier elements in this report. The well diagram from the report (figure 20, diagram to the left) shows a deep-set plug in the production tubing as the barrier. No account was taken of information in section 4.3.8 of the TMAP document that all pressure testing will affect the FCV and GLV control lines.

The activity programme for PP&A Well: 31/2-G-4 BY1H/BY2H approved in June 2016, on the other hand, leaves out the use of a deep-set plug without management of change (MOC). See also the section below. Well diagrams with and without a deep-set plug are shown in figures 9 and 10.

3.2.3 Risk review

Statoil’s internal requirements specify a detailed risk review when using a new barrier element. Meetings were held in connection with the review of risk at decision gates DG2 and DG3 for the project. According to information received, invitations to the meeting were sent to people in Songa Offshore and internally in Statoil. No participant lists are available from the risk review. Documentation received shows that representatives from the suppliers of subsea systems or FCV/GLVs (GE VetcoGray and Baker Hughes respectively) were not invited to participate. The Troll G-4 well planning group did not identify the risk of using the GLV and FCV as barrier elements with a VXT.

3.2.4 Management of change (MOC)

According to information which emerged during the investigation, great attention is paid to reducing costs and finding new ways to make operations more efficient. The Troll organisation has developed practices which were described in the investigation as “The Troll Way”. This expression describes the results of the long-standing attention paid to reducing costs and enhancing operational efficiency. In this case, changes to the plans have been introduced without adequate processes for identifying changes in the risk picture. During the interviews, it was claimed that the use of the FCV as a barrier element was approved in Statoil. However, documentation received in the wake of the incident shows that the company’s internal requirements as expressed in TR 2385 B.3.2 item 6 had not been met.

TR 2385 B.3.1 item 6: “The valve shall be documented to not shift position after it is put in closed position (being as a result of thermal or other erroneous operation through the pressure tubes. If erroneous operation is a risk, there shall be awareness and operational measures described in the installation procedure.”

It emerged during the interviews that the DOP 090 for pulling the TH was amended the day before by Statoil’s personnel offshore. This change comprised altering the time for closing the AP. According to the original DOP, that was to be done before connecting the retrieval tool. The risk of this amendment to the DOP was not adequately clarified either.

3.2.5 Expertise

It emerged from the interviews that several members of Statoil’s planning group lacked knowledge of VXT systems. That also applied to the drilling contractor, since this was the first time *Songa Endurance* was working on a well with a VXT system. The crew had little or no experience with VXTs delivered by VetcoGray. It was also claimed that insufficient time was provided for Songa Offshore’s drilling personnel to review the DOP before the operation started.

3.2.6 Reservoir properties on Troll

Information obtained from interviews shows that the Troll reservoir is very permeable and has properties which lead to seepage losses[1] of about 6-10m^3/h. Losing part of the fluid column in the well also leads to the loss of hydrostatic pressure, which thereby permits intrusion of reservoir fluids to the well.

The unintentional cycling of the GLV and FCV during the BOP wellhead connector test at 03.00 on 15 October 2016 meant that fluid drained out into the formation and gas from the reservoir filled the whole well beneath the TH.

3.2.7 Summary of underlying causes

- Inadequate planning of and compliance with procedures
- Inadequate management of change (MOC) process
- Inadequate technical, organisational and operational barriers
- Inadequate risk assessments
    - no detailed risk analyses in connection with selection of new method
    - inadequate understanding of risk
    - failure to involve personnel with relevant knowledge of equipment
- Inadequate expertise

[1] Seepage losses are defined as the loss of well fluids into the formation.

4 Potential of the incident

4.1 Actual potential

The actual consequences of the incident concern financial loss. These can be related to downtime connected to operation, replacing damaged drill-floor equipment, extensive and time-consuming work to normalise the well position, and deferred production.

Nobody suffered any physical injury during the incident.

The incident is not thought to have caused substantial harm to the natural environment. Emissions and discharges largely comprised gas and seawater. Those quantities not collected by the drain system ended up in the sea.

Twelve days passed before the unit was operational again after the incident.

4.2 Potential consequence

This was an incident with major accident potential, and one of the most serious well-control events on the NCS since the Snorre A incident in 2004. That assessment is based on the incident’s scale and potential.

If personnel had hesitated to close the BOP and the circumstances had caused gas ignition, the result could have been loss of human life and big material damage to the unit. There was little fluid left in the riser (about $11m^3$) when the AP was closed. The investigation team assumes that the fluid accompanying the gas reduced the ignition risk.

Had weather conditions been worse, there could have been a risk that the unit might be forced to disconnect from the lower marine riser package (LMRP) – including the AP. That could have harmed the environment through a flow of reservoir fluids from the well.

Had the bushings from the rotary table hit the driller’s cabin, serious personal injuries could have been caused and rapid shut-in of the well prevented. The investigation has not assessed the ability of the cabin to withstand this load.

If the AP in the BOP had failed during closure, the position could have developed into a full blowout.

The kill operation was conducted with a weakened BOP, where important barrier elements were not functioning. The BSR was on a level with the THSRT and the string could not be cut. The BSR is not designed to cut the THSRT.

Songa Endurance does not have a dedicated standby ship, but is intended to receive necessary assistance from the area vessel on Troll. The latter was two hours and five minutes sailing time from the location when the incident occurred.

The performance requirement for evacuation from *Songa Endurance* is 15 minutes. In this case, the POB check was completed in 28 minutes. In the event of a large blowout ignition, the fire could have spread to areas beyond the drill floor and thereby affected mustering and evacuation by lifeboat. The position of the area standby ship when the incident occurred means that its firewater capacity could not have contributed to safe evacuation of remaining personnel on *Songa Endurance*.

Ignition risk

Statoil has analysed the hazards presented by the gas in *Gas hazard analysis, gas leak on Songa Endurance 15.10.2016*. This report identifies the risk-reducing effect of the water in the riser which came up with the gas. It acted like water from a deluge facility. The flame acceleration simulator model (Flacs) used to assess the dispersal of the gas cloud has not proved suitable for a simultaneous escape of gas with a large volume of water. Neither this report nor Statoil's investigation report provide a quantitative assessment of the ignition potential, but is confined to a qualitative evaluation.

Large quantities of released gas escaped to the drill floor together with fluid in the riser. According to the Statoil report, the quantity emitted while the BOP was open was an initial 47.6kg/s rising to 70.7kg/s as the riser was emptied of fluid. This quantity gradually declined as the AP closed. If the AP in the BOP had not been activated as quickly as it was, the riser could have been emptied of water, the relative proportions of gas and water would have altered considerably, and the ignition threat would thereby have increased. The report shows that most of the gas would probably have flowed up vertically and vented through the top of the derrick. The gas detectors indicated gas both on and beyond the drill floor. Table 2 provides an overview of gas detectors activated during the incident.

Table 2 *Overview of gas detectors activated during the incident.*

Time	Alarm description	Level
09.33.31	Air intake HVAC to heavy tool store outside drill floor	20% LEL
09.33.35	Drill floor	20% LEL
09.33.36	Air intake HVAC to heavy tool store outside drill floor	20% LEL
09.33.41	Drill floor	60% LEL
09.33.50	Drill floor	20% LEL
09.34.29	Drill floor	60% LEL

Results from calculating gas dispersal with the aid of Flacs show that most of the gas would have moved upwards and out through the top of the derrick. Activation of gas detectors close to deck level was most probably caused by:

- falling fluid streams have carried gas with them in the turbulence
- gas has separated from the fluid
- the fluid flow from the rotary table has hit objects which spread fluid and gas horizontally.

About $11m^3$ of fluid remained in the riser when the AP was closed.

Gas from Troll consist largely of methane (94 per cent). Large quantities of gas filled the space above the drill floor during the incident. The 2.5-tonne slips and two bushings of one tonne each were thrown up from the rotary table. The bushings landed five-six metres from the rotary table and the slips followed the string down and landed on the diverter. This could have generated sparks and potentially led to ignition. The latter could have caused an explosion and potentially fatal conditions for the personnel in the driller’s cabin.

The driller’s cabin is protected by overpressure. If the bushings had breached netting and windows in the cabin, gas would have entered a space containing equipment which is not EX-proofed. At sufficient concentrations, this could have led to ignition.

The ESD system for equipment in the event of gas detection appears to have functioned in this incident and reduced the probability of ignition.

5 Observations

Observations by the PSA fall generally into two categories.

- Nonconformities: observations where it believes that regulations have been breached.
- Improvement points: observations where deficiencies are seen, but insufficient information is available to establish a breach of the regulations.

Five nonconformities and five improvement points have been identified. Several of the nonconformities are repeated in the planning and execution phases. A review of earlier investigation reports shows that the incident has clear similarities with those on Gullfaks C in 2010 and Snorre A in 2004.

5.1 Nonconformities

5.1.1 Compliance with procedures

Nonconformity
Inadequate compliance with procedures in connection with planning, management of change and execution of the operation.

Grounds
Suppliers were not involved in the planning phase, as Statoil’s procedure requires, in connection with the selection of the FCV and GLV as a barrier element. Cross-disciplinary involvement with and contribution to an overall risk assessment of the operation was thereby not ensured.

The MOC procedure was not complied with when amending the design of well barriers. No managed process was pursued when the FCV and GLV were chosen as the barrier element instead of a deep-set plug. The concept selection report was approved on 11 May 2016 with a deep-set plug. No account was taken of the information provided in section 4.3.8 of the TMAP document that any and all pressure testing would affect control lines to the FCV and GLV. The TMAP is not a formal procedure, but a description of experience with the way well operations should be executed on Troll, and is widely known in the field organisation. A deep-set plug is excluded from the plugging programme approved on 8 July 2016. New methods were introduced without adequate processes for identifying changes to the risk picture. See also section 2.1.7.

The consequences of the change to the DOP were not adequately analysed as required by the Statoil procedure for change management. Insufficient account was taken of important contributors to risk during detailed planning.

- It emerged from the interviews that DOP 090 for pulling the TH was amended. The time for closing the AP was changed without the consequences being analysed.
- The possible presence of gas under the TH was described in different ways at various points in the DOP.

No flow check was conducted immediately after shutting in the well, as required by the pressure control procedure. See also section 5.1.5.

Requirement
Section 24 of the activities regulations on procedures

5.1.2 Design of well barriers

Nonconformity
The FCV and GLV as a barrier element did not prevent an unintended influx of hydrocarbons to the well and a further uncontrolled outflow to the drill floor.

Grounds
The FCV and GLV were unintentionally opened during the BOP wellhead connector test. No other barriers were in place with sufficient independence between them.

The company could not demonstrate that internal requirements in TR 2385 B.3.2 point 6 were met. The FCV and GLV were not approved as barrier elements. See section 3.2.4 for further information.

Statoil's organisation was not aware of which performance requirements were set for the specific technical barrier elements (FCV and GLV) during either planning or operation. As mentioned in section 2.1.6, operational pressure on the FCV and GLV was 28-138 bar.

Requirements
Section 48, paragraph 2 of the facilities regulations on well barriers
Section 5 of the management regulations on barriers

5.1.3 Risk assessment as a decision base for improving the efficiency of the operation

Nonconformity
Risk assessments conducted before the decision to use the FCV and GLV as a barrier element failed adequately to identify risk conditions related to the change.

Grounds
The risk that the FCV and GLV could open under the influence of pressure was not identified. Design changes have been made without an adequate risk assessment.

Relevant suppliers did not attend the risk evaluation meeting for concept selection of 2 February 2016 nor the detailed planning meeting of 28 June 2016, which could have ensured that important safety issues with the chosen solution were better illuminated. The risk of replacing a deep-set plug with the FCV and GLV as a barrier element was not identified.

Requirements
Section 11 of the management regulations on the basis for making decisions and decision criteria
Section 17, paragraph 4, items a and b of the management regulations on risk analyses and emergency preparedness assessments

5.1.4 Expertise

Nonconformity
Personnel with responsibility for planning and executing the operation had limited expertise on the interaction between VXT systems and the FCV/GLV functions.

Grounds
It emerged from interviews that the responsible personnel from the operator and drilling contractor lacked sufficient expertise on the composition of the equipment and the interface between the TH and the FCV/GLV. See section 3.2.5 on expertise.

Statoil's Troll drilling organisation for the G-4 well had limited experience with VXTs.

Requirement
Section 21, paragraph 1 of the activities regulations on competence

5.1.5 Conduct of flow check

Nonconformity
No flow check was conducted immediately after the closure of the well.

Grounds
It emerged from interviews and document verification that no flow check had been conducted after the well was closed with the BOP and before the crew began to refill the riser. Refilling the riser made it difficult to monitor the well for possible inflows, and the leak through the choke thereby went undetected. This leak caused additional gas to flow into the well, and

meant that it took about 45 minutes for pressure in the annulus to stabilise. Pressure stabilised after a valve behind the choke was closed. See also section 2.3.

Requirement
Section 31, paragraph 1 of the activities regulations on monitoring and control

5.2 Improvement points

5.2.1 POB control during emergencies

Improvement point
POB control failed to meet the drilling contractor's own performance requirement during this incident.

Grounds
It was observed from interviews and the document review that it took 28 minutes to complete the POB check in connection with mustering after a general alarm. The performance requirement in Songa Offshore's governing document was 12 minutes.

Requirement
Section 77 of the activities regulations on handling hazard and accident situations

5.2.2 Training system for the emergency response team

Improvement point
Deficiencies in the training system for the well securing team.

Grounds
It emerged from interviews and document reviews that the training system for the well securing team had deficiencies. Such training (for CM skills) is not subject to the same system which applies for other emergency response teams.

Requirement
Section 6 of the management regulations on management of health, safety and the environment

5.2.3 Inadequate provision for quality assurance of the DOP

Improvement point
Inadequate provision for ensuring that DOP documents are used as intended.

Grounds
Documentation received and information obtained from interviews show that quality assurance of DOP documents is not always adequate. One reason given is that relevant personnel offshore lack the time to review and revise these documents.

Requirement
Section 24 of the activities regulations on procedures

5.2.4 Compliance with the pressure control manual

Improvement point
Compliance with the drilling contractor's pressure control manual was insufficient.

Grounds
Document reviews and interviews revealed non-compliance with requirements in the pressure control manual. Pursuant to the bridging document, it is Songa Offshore's pressure control manual which applies.

According to the manual, the drilling contractor is responsible for checking the status of barriers before starting the operation. See item 1.3 in the manual. This was not done.

Operator company personnel were not sufficiently familiar with the pressure control manual.

Requirements
Section 24, paragraph 2 of the activities regulations on procedures
Section 20 of the activities regulations on start-up and operation of facilities

5.2.5 Troll main activity programme (TMAP)

Improvement point
The TMAP document does not refer to the latest blowout and kill simulations conducted in 2014.

Grounds
The TMAP document received – see section 2.4 on relief wells – refers to blowout and kill simulations carried out in 2011. These showed that a well could be killed with one relief well. In connection with its consideration of the consent application for production drilling on the Troll field in September 2015, the PSA received a simulation report by Add Energy in December 2014. Updated simulations show that two relief wells are needed.

Requirement
Section 24, paragraph 2 of the activities regulations on procedures

6 Barriers

The incident occurred during preparations for the PP&A phase of the operation. In readying the well for a new sidetrack, the reservoir was to be isolated from the well. The FCV and GLV were defined as the primary barriers and the BOP as the secondary barrier in this well.

6.1 Barriers which functioned

6.1.1 BOP and isolation of the well

The AP in the BOP functioned as intended. Immediately before its activation, the BSR was activated with an operating pressure of 1 500 psi. The string could not be cut because the BSR was not designed to cut the THSRT. It took 38 seconds for the AP to close the annulus.

6.1.2 Drilling personnel (senior tool pusher and driller)

The drilling crew reacted quickly by closing the AP on the BOP.

6.1.3 Red zone on the drill floor

The red zone functioned as a barrier because nobody was out on the drill floor in the restricted area.

6.1.4 Ignition source control

The ESD system for equipment in the event of gas detection appears to have functioned in this incident and reduced the probability of ignition. The system for ignition source control on all Songa Offshore's Cat-D units is designed in accordance with the requirements in the HSE regulations for permanently installed facilities. These exceed the minimum requirements for mobile units on the NCS.

6.2 Overview of barriers which functioned/failed to function

The table below provides an overview of barriers which functioned/failed to function.

Date	Barriers which functioned	Barriers which failed to function	Technical barrier element	Organisational barrier element	Operational barrier element	Factors affecting performance
15 Feb 16		DG 2 risk analysis				X
28 Jun 16		DG3 risk analysis				X
		Decision to remove barrier element (deep-set plug)				X
15 Oct 16		FCV, GLV	X			
15 Oct 16		DOP				X
15 Oct 16	AP		X			
15 Oct 16	Sr tool pusher, driller			X		
15 Oct 16		BSR	X			
15 Oct 016	Red zone				X	
15 Oct 16		POB check			X	
15 Oct 16	Gas detection and ignition source control		X			
15 Oct 16		No flow test as soon as well shut in	X	X	X	

Table 3 *Overview of barriers which functioned and those which did not function.*

7 Discussion of uncertainties

How far the substantial volumes of water affected the functioning of fire and gas detectors on the drill floor is uncertain.

The reason for the high torque when connecting the THSRT to the TH is assessed in the report dated 22 November 2016 from supplier GE (GE VetcoGray – reference 164). This report draws no conclusions about the cause of the high torque.

8 Assessment of the investigation report from Statoil and Songa Offshore (A 2016-16 TPD L1)

Statoil and Songa Offshore decided to investigate the incident on 18 October 2016 and an investigation team was appointed on 20 October 2016. It was decided to conduct a joint Statoil-Songa Offshore investigation. The PSA received the report on 20 January 2017.

The investigation report by Statoil and Songa Offshore has identified direct and underlying causes of the incident on 15 October 2016. The report is presented in a detailed and orderly manner. It says little about why so many breaches of the companies' own governing documents occurred, and why management has not ensured compliance with procedures.

In addition, the report has paid little attention to the following.

- The reliability of the gas detectors when the air contains large quantities of water droplets. According to the investigation report, the ignition threat was underestimated because only two of the detectors registered 60 per cent LEL. These registrations are unlikely to have shown the actual position. During a major HC leak on Ula in 2012 when the water outlet from the main separator fractured, the old catalytic detectors were found to give a significantly faster and higher response than the new optical units.
- Had the riser been emptied of fluid, more or less pure gas would have been released. Virtually no assessment is made of which ignition sources and potential would have existed if the AP had been closed at a later time.
- The role of the standby ship in the worst conceivable outcome, with ignition. This concerns the spread of fire, which the vessel could have helped to contain with its firewater capacity while ensuring evacuation.

9 Appendices

A: HTO incident and cause-and-effect analysis.
B: List of documents utilised in the investigation.
C: Overview of personnel interviewed.